Generator Interconnection

Combined Feasibility and System Impact Study Report

90 MW Generation in
Ozaukee County, Wisconsin
MISO # G510 (#38429-02)

Prepared for the Midwest ISO

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1. Summary

This report contains a combined Interconnection Feasibility Study and System Impact Study for the Generation Interconnection Request MISO project #G510, MISO Queue #38429-02. This study evaluates the impact of 90MW in additional capacity to the Port Washington facility in Ozaukee County, Wisconsin. It also identifies system upgrades that will eliminate any identified unacceptable system impacts. The first block of generation is currently in place and the second block is scheduled to be placed in service by July 2008.

Port Washington was initially studied with a maximum capacity of 1200 MW (net) in the G093 (GIC027) interconnection study. Ten Megawatts of the 90 MW increase is an overall increase in turbine capacity during all operating temperatures. The remaining 80 MW's of additional capacity will primarily be available during winter operating periods. Since this is an increase in capacity to an existing facility, no new interconnection equipment is required. Figure 1.1 shows the system one-line diagram after the addition of G510.

This study identifies the thermal and steady state voltage violations, stability violations and system upgrades to eliminate these violations. Short-circuit impacts due to G510 were not evaluated since the generators are not being altered from what is currently installed or planned.

Further Study

A deliverability study is not required for this interconnection request since the additional 10 MW's of summer capacity was already granted as "Local Capacity Resource" in the MISO transition deliverability test. The customer has declined further deliverability analysis for this request.

A Facility Study is also not required for this request since the cost estimates and project schedules for all required facilities are included in the combined feasibility and impact study report.

Required Interconnection Facilities

Since this is an existing facility, no new interconnection facilities are required.

<u>Minimum permissible power factor at POI</u>

While ATC is not requiring a minimum permissible power factor for G510, the facility will be required to operate within good utility practice, adjusting the power factor of the facility to support the transmission system as required. The facility will be required to maintain a minimum of 1.02 p.u. voltage on the high side of the GSU transformers at all conditions unless ATC system operations directs otherwise.

Network Upgrades

<u>Existing System Before G510</u>

Stability Related (1 Block of generation operational)

There are no stability related problems prior to G510 with only 1 block of generation in service.

Stability Related (Both blocks of generation operational)
The required system upgrades to eliminate the stability violations prior to G510 are listed in Table 1.1. ATC will be responsible for replacing one relay and changing 3 relay settings at Saukville.

Breaker Duty Related
A fault duty study was not required for this request.

<u>Required Upgrades After G510</u>

Upgrades to facilitate the G510 interconnection
G510 is an increase in capacity for an existing facility. No facility related upgrades are required.

Stability Related (1 Block of generation operational - 2005)
There are no stability related problems due to G510 operating with only 1 block of generation.

Stability Related (2 Blocks of generation operational - 2008)
The required system upgrades to eliminate the stability violations prior to G510 are listed in Table 1.1. G510 will be responsible for the cost associated with 4 relay setting changes at Saukville.

Breaker Duty Related
The G510 generation increase does not add additional fault current to the system. Therefore, no upgrades in this regard are required before the in-service date of G510.

Network Resource (NR) Certification Related
A deliverability study is not required for this interconnection request since the additional 10 MW's of summer capacity was already granted as "Local Capacity Resource" in the MISO transition deliverability test. The customer has declined further deliverability analysis for this request.

Injection Upgrades
The injection upgrades refer to those upgrades that eliminate thermal violations in the close electrical proximity to G510. The injection upgrades are required for both Network Resource (NR) and Energy Resource (ER) services. There were no injection upgrades identified in the power flow analysis. The customer should note that a deliverability analysis has not been performed for G510.

Operation Restrictions

The N-2 linear transfer analysis identified three operation restrictions on G510 due to thermal constraints. No operating restrictions were identified for prior outage stability or steady state voltage analysis.

Additional Power Flow Analysis Results for Informational Purpose

The power flow analysis did not identify any injection related upgrades. Refer to section 3.3 for more discussions on the subject and Appendix C for the analysis results.

Table 1.1 – Stability Upgrades Required

Existing System Upgrades				
Location	**Equipment**	**Work Required**	**Year Required**	**Cost Estimate (2006 Dollars)**
Saukville Substation	8231 BF Relay	Reset Relay for a total of 11.5 cycles	2008	$2692
	8232 BF Relay	Reset Relay for a total of 11.5 cycles	2008	$2692
	8252 BF Relay	Reset Relay for a total of 12.0 cycles	2008	$2692
	T1-138 BF Relay	Replace Relay with SEL 352 Reset Relay for a total of 11.5 cycles	2008	$12511
			Total Cost	$20,587

Network Upgrades				
Location	**Equipment**	**Work Required**	**Year Required**	**Cost Estimate (2006 Dollars)**
Saukville Substation	2642 BF Relay	Reset Relay for a total of 12.0 cycles	2008	$2692
	8241 BF Relay	Reset Relay for a total of 12.0 cycles	2008	$2692
	8253 BF Relay	Reset Relay for a total of 12.0 cycles	2008	$2692
	8263 BF Relay	Reset Relay for a total of 12.0 cycles	2008	$2692
			Total Cost	$10,768

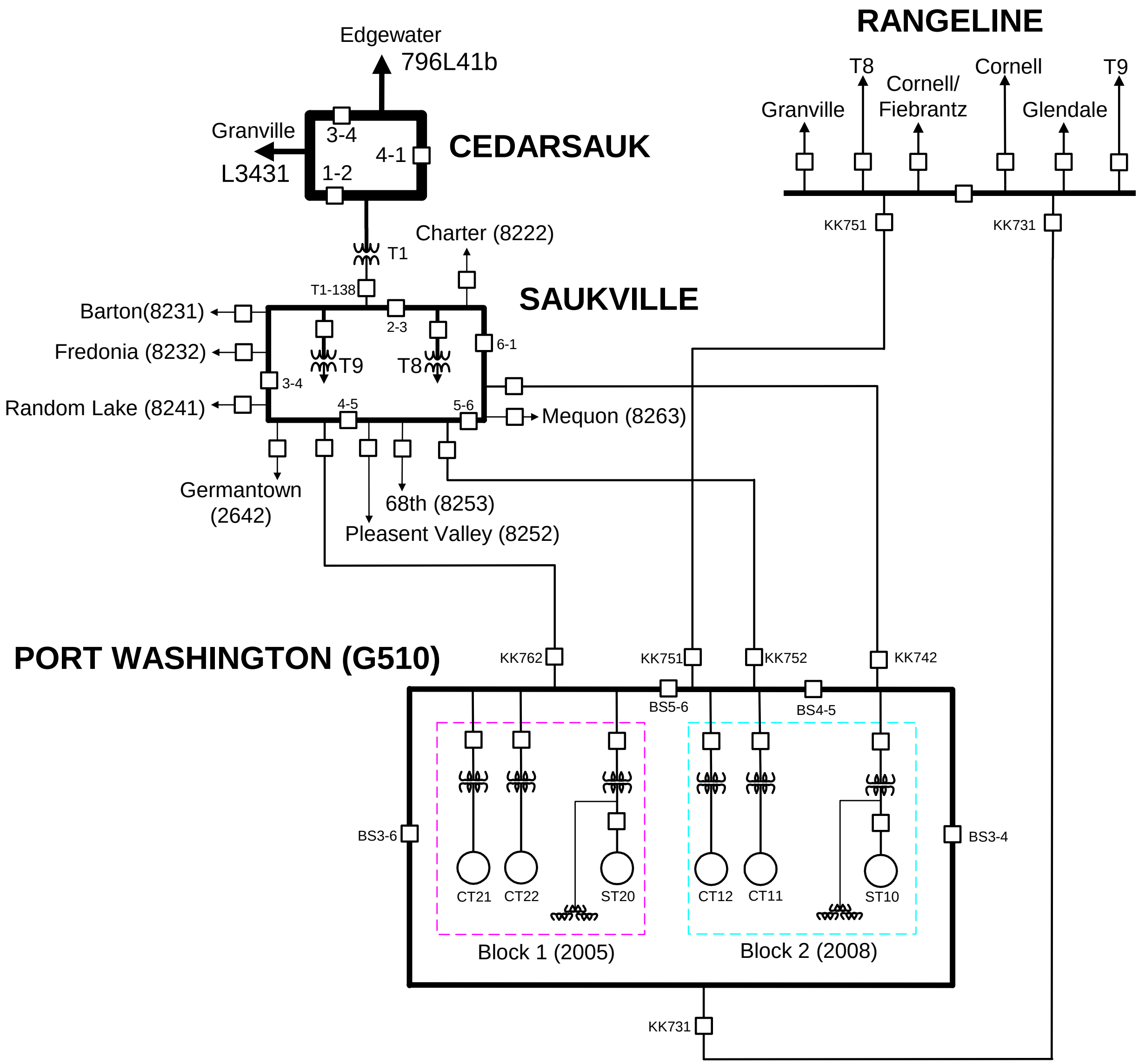

Figure 1.1 – One Line Diagram of the System with G510

2. Criteria, Methodology and Assumptions

2.1 Study Criteria

All relevant MISO-adopted NERC Reliability Criteria and the ATC contingency criteria are to be met for both the stability analysis and the thermal analysis. Details of the stability and thermal analysis criteria applied in this study can be found in the Appendix.

2.2 Study Methodology

The results of this study are subject to change. The results of the Study are based on data provided by the Generator and other ATC system information that was available at the time the study was performed, and the injection study does not guarantee deliverability to the MISO energy market. If there are any significant changes in the generator and controls data, in earlier queue Generator Interconnection Requests, in related Transmission Service Requests, or ATC transmission system development plans, then the results of this study may also change significantly. Therefore, this request is subject to restudy. The Generator is responsible for communicating any significant generation facility data changes in a timely fashion to ATC prior to commercial operation.

2.2.1 Competing Generation Requests

ATC determined in its sole judgment that two Generator Interconnection Requests with an earlier queue position will impact the G510 study results. G012 and G093 are considered competing requests for the interconnection of this generator and therefore included in each base case. G012 is the original 1000 MW request for the Port Washington facility and G093 is a request for 200 MW of additional capacity. Only the first block of Port Washington generation is in-service at this time, with the second block due in-service by 2008.

Public information related to Generator Interconnection Request queue can be found via the MISO web site at **http://oasis.midwestiso.org/documents/ATC/queue.html**

2.2.2 Before and After Comparison Approach Employed in Stability Analysis

In the stability analysis performed for this study, to identify what impacts should be attributed to the addition of G510 interconnection; two system conditions were examined - “Before” the addition of G510 and “After” the addition of G510. Any violations of the stability study criteria identified in the “Before” state are defined to be existing system violations. Any new violations identified in the “After” state or violations identified in both “Before” and “After” states and are worse in the “After” state are to be attributed to the addition of G510. Only those existing system violations that are made worse by G510 are deemed relevant to the G510 interconnection request and are documented in this report. Any other identified existing system violations that are not made worse by G510 are deemed unrelated to the G510 interconnection request and are documented elsewhere as part of the internal ATC planning projects.

The stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-29 (PSS/E, Version 29) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis.

2.2.3 Linear Transfer Analysis and A.C. Power Flow Analysis Methods

For steady-state voltage evaluation under normal, N-1 and special ATC multiple contingency conditions, AC Contingency Calculation (ACCC) method was used. For thermal overload evaluation under, N-1 and N-2 conditions, Linear Transfer Analysis method was used with adjusted MW ratings to account for reactive power flows. For steady state voltage stability analysis under N-2 contingencies, ACCC method was used.

The Linear Transfer analysis was performed using the Linear Transfer Analysis modules of the Managing and Utilizing System Transmission-6.03 (MUST, Version 6.03) program from Power Technologies, Inc (PTI). ACCC was performed using the Power Flow module of the Power System Simulation/Engineering-29 (PSS/E, Version 29) program from Power Technologies, Inc (PTI). These programs are accepted industry-wide for power flow analysis.

2.2.4 Base Cases

2.2.4.1 Power flow analysis

Power flow analysis includes evaluation of thermal and steady state voltage violations in the intact system and under N-1 contingencies and evaluation of thermal violations and steady state voltage stability under N-2 contingencies. For power flow analysis, two system conditions were evaluated, which represent expected winter 2007 and 2008 conditions. Base cases used in the power flow analysis were developed based upon the MISO (Midwest Independent System Operator) seasonal cases of winter 2007 and winter 2008. The MISO seasonal cases are accessible through the MISO Extranet. The 90MW G510 generation was delivered to all loads within MISO footprint.

2.2.4.2 Stability analysis

Since Port Washington is being installed in two separate blocks of generation, multiple sensitivities had to be performed to determine any impacts in the stability performance of the generator. The first block of generation is currently in service and has the capability of 625 MW under light load and 660 MW during winter periods of operation. The second block is due in service July 2008, and will increase the plant's total capacity to 1251 MW during light load periods and 1320 MW during winter periods. For the 2005 time period, only the "After" scenario was studied since no stability problems were identified with only one block of generation operational. For the 2008 time period, a "Before" with Port Washington generating 1230 MW's (light load) was compared against an "After" with Port Washington generating 1251 MW (light load) and 1320 MW (winter).

The 2005 and 2008 50% summer peak cases were developed based on the NERC 2004 series MMWG (Multi-Regional Modeling Working Group) base cases. The 2008 light load and winter shoulder cases were created using the 50% peak case, scaling the load in the ATC areas to levels as predicted within the EIA 411 load forecast for 2008, dispatching generation in the ATC footprint according to merit order dispatch. The G510 generation was delivered 75% to the Common Wealth Edison (ComEd) control area and 25% to the Northern State Power (NSP) control area.

2.2.4.3 Deliverability analysis

Deliverability analysis will not be required for this study.

2.3 Assumptions

2.3.1 Generation Facility Modeling

The G510 facility was modeled using the as-built data submitted to ATC for the first block of generation. Using projected generation output curves supplied by the customer, corresponding MW and MVAR adjustments were made to model using the existing generator capability curves.

Unless specified otherwise, the G510 facility was modeled with the plant operating with a GSU high side voltage of 1.02 p.u. for stability analysis.

3. Analysis Results

3.1 Stability Analysis Results

The stability criteria used in this study requires that all machines modeled in the system must remain stable after a three-phase or single-phase to ground fault is cleared from any transmission element under the following conditions:

1) Three-phase fault cleared in primary time with an otherwise intact system;
2) Three-phase fault cleared in primary clearing time with a pre-existing outage of any other transmission element;
3) Single Line Ground (SLG) bus section fault cleared in primary clearing time with an otherwise intact system;
4) SLG internal breaker fault cleared in primary clearing time with an otherwise intact system.

The stability criteria also require that all machines remain stable for a fault cleared in delayed clearing time (i.e. breaker failure conditions) with an otherwise intact network. Wind turbines are exempt from this criterion, but must not aggravate network performance.

Results of the stability analysis are summarized in Tables A.1 through A.4 in Appendix A.

3.1.1 Results of Intact System Primary Fault Contingencies

The intact system primary fault contingencies evaluated and the study results are summarized in Table A.1 in Appendix A.

Before G510

The study identified no unacceptable stability performance for any of the studied intact system primary fault contingencies in the existing system.

After G510

The study identified no unacceptable stability performance for any of the studied intact system primary fault contingencies with the addition of G510.

3.1.2 Results of Delayed Clearing Contingencies

The breaker failure contingencies evaluated and the study results are summarized in Table A.2 in Appendix A.

Before G510

The study identified four contingencies with unacceptable stability performance for the studied breaker failure contingencies in the existing system. One of these contingencies will require relay package upgrade and 3 of them will require relay setting changes.

Several pre-existing problems were identified at the Saukville substation for 2008 that were not previously identified in the G093 study with both blocks of Port Washington operational. It was determined that the as-built data that was supplied to ATC for the first block of Port Washington generation differs from what was supplied at the time the G093 interconnection study was performed. The change in data is responsible for causing the pre-existing stability related problems not found in the G093 study. The “before” state assumes that the second block of generation will contain identical parameters as was supplied to ATC for the first block of generation. The required system upgrades to eliminate the stability violations prior to G510 are listed in Table 1.1.

After G510

The study identified eight contingencies with unacceptable stability performance for the studied breaker failure contingencies with G510. Four contingencies were identified as pre-existing problems and are not due to the addition of G510. The remaining 4 contingencies will require relay setting changes and are the responsibility of G510.

3.1.3 Results of Prior Outage Primary Fault Contingencies

The prior outage contingencies evaluated and the study results are summarized in Table A.3 in Appendix A.

Before G510

The study identified no unacceptable stability performance for any of the studied prior outage primary fault contingencies in the existing system.

After G510

The study identified no unacceptable stability performance for any of the studied prior outage primary fault contingencies after the addition of G510.

3.1.4 Results of Internal Breaker Fault and Bus Section Fault Contingencies

Three internal breaker fault/bus section fault contingencies were evaluated for Single-Line to Ground (SLG) fault, the result of which is shown in Tables A.4 in Appendix A. The study identified no unacceptable stability performance for these types of faults.

3.2 Short-Circuit Analysis Results

Short-circuit analysis was not performed since the request will not introduce any additional fault current to the transmission system. No system upgrades due to breaker duty are required prior to the interconnection of G510.

3.3 Power Flow Analysis Results

3.3.1 Determination of the Minimum Power Factor Requirement

Since G510 is an increase in capacity for a fossil fuel power plant, a minimum power factor requirement will not be identified for this request. The plant will be required to operate within good utility practice, which typically requires the facility to maintain 1.02 p.u. voltage on the high side of the GSU transformer.

3.3.2 Results of Single Contingencies (N-1)

The study identified no steady-state voltage violations due to G510 for all intact and single contingencies studied.

The study identified two thermal violations for 2007 and 2008 prior to the addition of G510 under N-1 condition, as summarized in Table C.1 in Appendix C. The Bain – Kenosha 138 KV limit (line 63151) is a relay limit and is currently being planned to be replaced in 2005. The Oak Creek T884 230/345 kV transformer is typically addressed through an operating guide. No transmission improvements currently planned to eliminate this overload condition.

3.3.3 Results of Double Contingencies (N-2)

Thermal constraints and steady state voltage stability were evaluated for a number of N-2 contingencies. These contingencies involve outages on two transmission elements in the electrical proximity of G510. The purpose of the N-2 analysis is to reveal the violations and identify operation restrictions to eliminate the violations under prior outage conditions, which provides guidance for any future Operating Guides needed for G510 in real time operation.

3.3.3.1 Thermal analysis

Thermal violations under a selected number of N-2 contingencies were evaluated using linear transfer analysis method. The study identified three thermal violations that are made worse with the addition of G510. Therefore, operation restrictions due to thermal overloads are necessary and listed in Table D.1.

3.3.3.2 Steady state voltage stability analysis

The goal of this analysis is to identify the N-2 contingencies, under which AC power flow solutions diverge. Divergence of a power flow solution indicates potential voltage collapse. If any such double contingency is identified, an operation restriction is also identified for which the power flow solution converges. This analysis was performed using the ACCC function in PSSE and for a selected number of N-2 contingencies in the electrical vicinity of G510. The 2007 and 2008 winter case was used for this analysis. No double contingencies caused divergence of power flow solutions. Therefore, no additional operation restrictions are necessary due to steady state voltage stability concerns under N-2 contingencies.

Appendix A

Stability Analysis Results

Notes applicable to Tables A.1 through A.4:

1. Substation name abbreviations: POW – PORT WASHINGTON, SAU – SAUKVILLE, RNG – RNAGELINE, MEQ – MEQUON, PVL – PLEASEENT VALLEY, 68^{TH} – 68^{TH} STREET, RND – RANDOM LAKE, MPL – MAPLE/GERMANTOWN, FRD – FREDONIA, BAR – BARTON, CHR – CHARTER STEEL, COR – CORNELL, GLN – GLENDALE
2. Color scheme – Green represents acceptable stability performance; Red represents unacceptable stability performance; bolded **blue** highlights new or upgraded equipment.
3. Fault is three-phase and applied at from end of the "Faulted Facility" unless specified otherwise.
4. WNS – Was Not Simulated. A particular contingency was not simulated for a particular season because the outcome is predictable based on the simulation for the other season, or the outcome would not affect the conclusion of acceptable/unacceptable stability performance or the required upgrade for this contingency.
5. **(RS)** – Relay Setting Change Required
6. **(RR)** – Breaker Failure Relay Replacement Required.
7. Option A - Cornell – Rangeline rebuild not implemented and Cornell – Fiebrantz (L3611) operated normally open.
8. Option B - Cornell – Rangeline rebuild not implemented and Cornell – Fiebrantz (L3611) operated normally closed with a 4.5 ohm series reactor installed at Cornell substation.

Table A.1 – Stability Analysis Results of Intact System Primary Fault Contingencies For the Expected 2008 Systems Before and After the Addition of G510 Generation

Item	Faulted Facility	Fault Location	Near, Far Ends Primary Clearing Time (Cycles)[A]	Pre-exist system	With G510		Fixes
	From – To Ckt			2008 50% Peak Load or 2008 Winter Shoulder	2008 50% Peak Load G510 @ 1251MW Option A	2008 Winter Shoulder G510 @ 1320MW Option A	2008 50% Peak Load and 2008 Winter Shoulder
1	MEQ – SAU	MEQ	6.0, 24.0	WNS	Acceptable	Acceptable	None
2	RND – SAU	RND	6.0, 24.0	WNS	Acceptable	Acceptable	None
3	68^{th} – SAU	68^{th}	6.0, 24.0	WNS	Acceptable	Acceptable	None
4	BAR – SAU	BAR	6.0, 24.0	WNS	Acceptable	Acceptable	None
5	PVL – SAU	PVL	6.0, 24.0	WNS	Acceptable	Acceptable	None
6	FRD-SAU	FRD	6.0, 24.0	WNS	Acceptable	Acceptable	None
6	MPL – SAU	MPL	6.0, 24.0	WNS	Acceptable	Acceptable	None
9	CHR – SAU	CHR	6.0, 18.0	WNS	Acceptable	Acceptable	None
10	POW - RNG	POW	10.0, 6.0	WNS	Acceptable	Acceptable	None
11	POW – SAU	POW	10.0, 6.0	WNS	Acceptable	Acceptable	None
12	SAU T1 138kV side	SAU 138kV	10.0, 6.0	WNS	Acceptable	Acceptable	None
13	SAU – FRD	SAU 138kV	10.0, 6.0	WNS	Acceptable	Acceptable	None

Notes:

A. Near and Far Ends Primary Clearing Times are approximate values and not actual settings in the field.

Table A.2 – Stability Analysis Results of Delayed Clearing Contingencies
For the Expected 2005 and 2008 Systems Before and After the Addition of G510 Generation

Item	Faulted Facilities	Failed Circuit Breaker	Element(s) Cleared In Breaker Failure	Backup Breaker Clearing Time Actual[B] (Cycles)	Far End Primary Clearing Time, Actual[A] (Cycles)	G510 @ 625 MW (After) 2005 50% peak load 1.02 VS		G510 @ 660 MW (After) 2005 Winter Shoulder 1.02 VS		G510 @ 1230 MW (Before) 2008 50% peak load 1.02 VS		G510 @ 1251 MW (After) 2008 50% peak load 1.02 VS		G510 @ 1320 MW (After) 2008 Winter Shoulder 1.02 VS	
						Required Clearing Time	Required Changes	Required Clearing Time	Required Changes	Required Clearing Time Option A	Required Clearing Time Option B	Required Clearing Time Option A	Required Clearing Time Option B	Required Clearing Time Option A	Required Clearing Time Option B
1	POW-SAU	POW 742	POW BS3-4, BS4-5, T7	10.35	~6.0	WNS	None	WNS	None	11.5	None	11.5	WNS	11.0	WNS
2	POW-SAU	POW 752	POW BS4-5, BS5-6, 751	10.35	~6.0	WNS	None	WNS	None	11.0	None	11.0	WNS	11.0	WNS
3	POW-RNG	POW 751	POW BS4-5, BS5-6, 752	10.35	~6.0	WNS	None	WNS	None	11.0	None	10.5	WNS	10.5	WNS
4	POW-SAU	POW 762	POW BS3-6, BS5-6, T8	10.35	~6.0	WNS	None	WNS	None	12.0	None	12.0	WNS	11.5	WNS
5	POW-RNG	POW 731	POW BS3-6, BS3-4	10.35	~6.0	WNS	None	WNS	None	11.0	None	10.5	WNS	10.5	WNS
6	POW-T7	POW T7	POW BS3-4, BS4-5, 742	N/A	~6.0	WNS	None	WNS	None	11.5	None	11.0	WNS	11.0	WNS
7	POW-T8	POW T8	POW BS3-6, BS5-6, 762, T8	N/A	~6.0	WNS	None	WNS	None	12.0	None	12.0	WNS	11.5	WNS
8	SAU-MEQ	SAU 8263	SAU 6-1, 742, 5-6	12.4	~6.0	13.5	None	13.5	None	12.5	12.5	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**
9	SAU-PVL	SAU 8252	SAU 5-6, 752, 8253, BS4-5	12.1	~6.0	13.5	None	13.5	None	12.0 **(RS)**	12.5 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**
10	SAU-68[th]	SAU 8253	SAU BS5-6, 752, 8252, BS4-5	12.4	~6.0	13.5	None	13.5	None	12.5	12.5	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**
11	SAU-RND	SAU 8241	SAU BS4-5, 762, BS3-4, 2642	12.4	~6.0	13.5	None	13.5	None	12.5	12.5	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**
12	SAU-MPL	SAU 2642	SAU 4-5,762,3-4,8241	12.4	~6.0	13.5	None	13.5	None	12.5	12.5	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**	12.0 **(RS)**
13	SAU T1	SAU T1-138	SAU BS3-4, 8232, T9-138, 8231, BS2-3	13.4	~6.0	13.5	None	13.5	None	12.0 **(RR)**	12.0 **(RR)**	11.5 **(RR)**	12.0 **(RS)**	11.5 **(RR)**	11.5 **(RR)**
14	SAU-FRD	SAU 8232	SAU BS3-4, T1-138, T9-138, 8231, BS2-3	12.4	~6.0	13.0	None	13.5	None	12.0 **(RS)**	12.0 **(RS)**	11.5 **(RS)**	11.5 **(RS)**	11.5 **(RS)**	11.5 **(RS)**
15	SAU T9	SAU T9-138	SAU BS3-4, 8232,T1-138, 8231, BS2-3	N/A	~6.0	13.0	None	13.5	None	11.5	12.0	11.5	11.5	11.5	11.5
16	SAU-BAR	SAU 8231	SAU BS3-4, 8232, T9-138, T1-138, BS2-3	12.4	~6.0	13.0	None	13.5	None	12.0 **(RS)**	12.0 **(RS)**	11.5 **(RS)**	11.5 **(RS)**	11.5 **(RS)**	11.5 **(RS)**
17	SAU-CHR	SAU 8222	SAU BS2-3, BS6-1, T8-138	12.4	~6.0	14.0	None	14.0	None	13.0	13.0	12.5	13.0	12.5	13.0
18	SAU T8	SAU T8-138	SAU BS2-3, BS6-1, 8222	N/A	~6.0	14.0	None	14.0	None	13.0	13.0	12.5	13.0	12.5	13.0
19	SAU-POW	742	SAU BS6-1, 8263, BS5-6	11.85	~6.0	14.0	None	14.0	None	12.5	13.0	12.5	12.5	12.5	12.5
20	SAU-POW	752	SAU BS5-6, 8252, 8253, BS4-5	11.85	~6.0	14.0	None	14.0	None	12.5	13.0	12.0	12.5	12.0	12.5
21	SAU-POW	762	SAU BS4-5, 2642, BS3-4, 8241	11.85	~6.0	14.0	None	14.0	None	12.5	13.0	12.5	12.5	12.0	12.5
22	RNG T7	RNG 61441	RNG 61442, 61443, BS4-5, 731	N/A	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
23	RNG-POW	RNG 731	RNG 61442, 61441,BS4-5, 731	13.85	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
24	RNG-COR	RNG 61443	RNG 61442, 61441, BS4-5, 731	14.5	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
25	RNG-GLN	RNG 61442	RNG 61441, 61443, BS4-5, 731	14.65	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
26	RNG T8	RNG 61452	RNG 61451, 61453, BS4-5, 751	N/A	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
27	RNG-COR	RNG 61451	RNG 61452, 61453, BS4-5, 751	14.5	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
28	RNG-POW	RNG 751	RNG 61452, 61453, BS4-5, 61451	13.85	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS
29	RNG-GVL	RNG 61453	RNG 61452, 751, BS4-5, 61451	14.5	~6.0	WNS	None	WNS	None	>15.5	None	>15.5	WNS	>15.5	WNS

Notes:
A. Far End Primary Clearing Time are approximate test limits and not actual settings in the field.
B. Breaker failure clear times are exact figures obtained from System Protection.

Table A.3 – Stability Analysis Results of Prior Outage Primary Fault Contingencies For the Expected 2008 Systems Before and After the Addition of G510 Generation

Faulted Facility	Pre-existing System Outage	Near and Far Ends Primary Clearing Time (Cycles) [A]	Pre-exist system		With G510			
From –To Ckt	From–To Ckt		2008 50% Peak Load	2008 Winter Shoulder	2008 50% Peak Load G510 @ 1251MW Option A	Allowable MW Output & Power Factor Restriction	2008 Winter Shoulder G510 @ 1320 MW Option A	Allowable MW Output & Power Factor Restriction
POW–SAU 1	POW–RNG 1	10.0,6.0	WNS	WNS	Acceptable	None	Acceptable	None
	POW–SAU 2	9.0,6.0	WNS	WNS	Acceptable	None	Acceptable	None
	SAU T1 345/138 kV	10.0,6.0	WNS	WNS	Acceptable	None	Acceptable	None
	SAU-CHR 1	10.0,6.0	WNS	WNS	Acceptable	None	Acceptable	
POW–RNG 1	POW-RNG 2	10.0,6.0	WNS	WNS	Acceptable	None	Acceptable	None

Notes:
A. Near and Far Ends Primary Clearing Times are approximate test limits and not actual settings in the field.

Table A.4 – Stability Analysis Results of Breaker Internal or Bus Section Fault For the Expected 2008 System After the Addition of G510 Generation

Faulted Facility[A]	Element(s) Cleared In Primary	Primary Clearing Time (Cycles)[B]	With G510		Fixes
			1251 MW 2008 50% Peak Load Option A	1320 MW 2008 Winter Shoulder Option A	
SAU BS2-3	SAU bus sections 2,3	10.0	Acceptable	Acceptable	None
SAU BS3-4	SAU bus sections 3,4	10.0	Acceptable	Acceptable	None
SAU BS4-5	SAU bus sections 4,5	10.0	Acceptable	Acceptable	None
SAU BS5-6	SAU bus sections 5,6	10.0	Acceptable	Acceptable	None

Notes:

A. Single-phase ground fault
B. Primary Clearing Times are test limits and not actual settings in the field.

Appendix B

Short Circuit Analysis Results

(Not Performed)

Appendix C

Power Flow Analysis Results

Table C.1 – Identified Thermal Violations Prior to G510 under N-1 Contingencies

Limiting Element	Existing MVA Rating [1]	Worst MVA Loading	Worst Contingency	TDF	Base Case Description
Bain – Kenosha 138 kV line	287	328	Zion – Pleasant Prarie 345 kV line	0.08193	Winter 2007
Oak Creek 230/345 kV Transformer	300	381	Oak Creek Bus Section 9 230 kV	0.05375	Winter 2007
Bain – Kenosha 138 kV line	287	314	Zion – Pleasant Prarie 345 kV line	0.07968	Winter 2008
Oak Creek 230/345 kV Transformer	300	358	Oak Creek Bus Section 9 230 kV	0.05434	Winter 2008

Notes:

1. Winter emergency rating for contingency violations.

Appendix D

Summary of Operation Restrictions

Table D.1 – Summary of the Identified Operation Restrictions on G510

Prior outage	Allowable MW Output of G510 & Power Factor Restriction	Worst Next Contingency	Limiting Elements	MVA Rating	Reason
Any one of the Port Washington – Saukville 138kV lines. KK742, KK752 or KK762	0 MW	Any remaining 138 kV line from Port Washington to Saukville.	Line Conductor	658 WE 617 FE 577 SE	Thermal

Note:

1. Outage in any two Port Washington – Saukville 138 kV lines results in an overload in the third. Significant reductions in generation will be required for this contingency
2. WE – Winter Emergency Rating, FE – Fall Emergency Rating, SE – Summer Emergency Rating

Appendix E

Study Criteria

Study Criteria

E.1 Contingencies

For stability analysis, a set of branches in the vicinity of the generator/power plant of concern is selected as contingencies, based on engineering judgment. Fault analysis is performed for the following six categories of contingency conditions:

1. Three-phase fault cleared in primary time with an otherwise intact system.
2. Three-phase fault cleared in delayed clearing time (i.e. breaker failure conditions) with an otherwise intact system.
3. Three-phase fault cleared in primary clearing time with a pre-existing outage of any other transmission element.
4. Single Line Ground (SLG) bus section fault cleared in primary clearing time with an otherwise intact system.
5. SLG internal breaker fault cleared in primary clearing time with an otherwise intact system.
6. SLG fault of double circuits on common tower cleared in primary time with an otherwise intact system.

For power flow analysis, contingencies include:

1. N-1 contingencies – all lines and transformers operated at 69kV and above in the following control areas/zones: ATC Planning Zones 1-5 and ties to those zones and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant West control areas.
2. Selected N-2 and multiple contingencies that ATC has determined to be significant.

E.2 Monitored Elements

E.2.1 Intact System, N-1 and Special Multiple Contingency Evaluation Using ACCC

All load carrying elements operated at 69kV and above in the following control areas/zones were studied: ATC Planning Zones 1-5, ties to those zones and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant West control areas.

E.2.2 N-2 Contingency Evaluation Using Linear Transfer Analysis Method

All load carrying elements operated at 69kV and above in the following control areas/zones were studied: ATC Planning Zones 1-5, ties to those zones and all branches of voltage level 69kV and above in the Dairyland Power Cooperative, Northern States Power Control Area, Commonwealth Edison, and Alliant West control areas.

E.3 Thermal Loading Criteria

E.3.1 Intact System, N-1 and Special Multiple Contingency Evaluation Using ACCC

Under intact system conditions, the loading of all transmission elements with distribution factors greater than 0.05 per unit must not exceed the applicable normal rating (Rate A). Under contingency conditions, the loading of all transmission system elements with distribution factors greater than 0.03 per unit must not exceed the applicable emergency rating (Rate B).

E.3.2 N-2 Contingency Evaluation Using Linear Transfer Analysis Method

Under N-2 contingency conditions, the loading of all transmission system elements with distribution factors greater than 0.03 per unit must not exceed 95% of the applicable emergency rating.

E.3.3 Injection Violations

Generation injection violations include 1) thermal violations of the transmission elements that connect the Generator to the rest of the transmission network (outlet congestion); 2) thermal violations of the transmission elements that have TDF ≥ 20% anywhere in the studied system.

E.4 <u>Steady State Under Voltage Criteria</u>

E.4.1 Intact System, N-1 and Special Multiple Contingency Evaluation Using ACCC

Under intact system conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 per unit due to the Generator must not be lower than 0.95 per unit. Under contingency conditions, the voltage magnitude of all transmission system buses with a decrease of 0.01 per unit due to the Generator must not be lower than 0.90 per unit.

E.4.2 N-2 Contingency Evaluation

Power flow solutions must converge for a selected number of N-2 contingencies in the electrical proximity of the studied Generator. Divergence of a power flow solution indicates potential voltage collapse.

E.5 <u>Stability Criteria</u>

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by ATC (0.5 cycle in this study due to as-built data being used), it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable stability performance.

In the context of stability analysis, voltages of all transmission system buses must recover to be at least 70% of the nominal system voltages immediately after fault removal and 80% of the nominal system voltages in 0.5 second after fault removal.